February 12, 2002

California Power Authority
901 P Street, Suite 142A
Sacramento, CA 95814

Dear Authority:

Re: Southern California Edison's Comments on the California Power Authority's ("CPA") Draft Investment Plan

The following represents most of the concerns Southern California Edison ("SCE") expressed in late January regarding the CPA's Draft Investment Plan ("DIP"). As a prelude to our comments, we believe an overview of the statutory provisions establishing the requirements and purposes of the CPA's Investment Plan ("Plan") are in order.

In summary, the CPA's enabling legislation provides a clear and concise mandate to finance or otherwise provide financial assistance for **cost effective** energy resource investments[1] which are needed to **supplement** public and private power supplies[2] and which provide electricity to consumers **at cost**[3].

Recommendations for investments in new grid renewables, existing grid renewables, micro-turbines and green peakers found in the CPA's Draft Investment Plan ("DIP") appear inconsistent with this mandate, both in terms of need and cost-effectiveness. Efforts involved with developing active load management systems appear sound, although the implementation, program structure and incentive details of such efforts appear sketchy at best.

SCE believes the Plan needs to adhere to the principles outlined in statute. Namely, only after there is a determined need for new resources, after considering those likely to be provided by others, should the CPA pursue new additions. Then, only the most-efficient and cost-effective resources available. Furthermore, in assessing the cost-effectiveness, it is mandatory the CPA reflect all the costs necessary to integrate and operate the Plan, not just the assumed investment requirements.

[1] PUC Code 3369.c
[2] PUC Code 3310.a
[3] PUC Code 3351.a

Before we address our major concerns, we would like to indicate that the DIP is incorrect by implying a lack of diversity for SCE. SCE not only has one of the best conservation records in the nation, we also have one of the nation's most diverse energy supply portfolios, with 13% renewable, 16% cogeneration, 19% nuclear, 12% coal, 10% hydro (includes hydro purchases/exchanges), and the remaining 29% being supplied from DWR natural gas purchases. The only area where there has been any lack of diversity, was the lack of price and procurement diversity we faced in complying with the State's mandate to purchase all of our requirements directly from the dysfunctional ISO and PX markets.

Major Comments and Observations:

From SCE's Perspective, There Is Limited Resource Need

The DIP's assessment of need to justify their pursuit of 3,500 MW of new resources, appears to ignore substantial changes in the state's resource outlook since the passage of SB6x. Our present projections indicate little to no need for additional baseload resources over the next four years as a result significant changes in load requirements and resource supply additions within California. Included are:

- Significant electric conservation response from customers which is expected to continue for several years with only modest degradation;
- State's aggressive adoption of new energy efficiency programs, which augment the $245 million/year already available for up to 10 years from PGC funds[4];
- DWR's procurement of nearly 12,000 MW of mainly baseload resources;
- Potential for 15% of existing energy requirements being served via direct access;
- Completion of at least 8,000 MW of new generation (3,000 MW in operation since SB6x, and another 5,000 MW well into construction);
- 1,300 MW of new renewable resources from the CEC's Renewable Program, with about 800 MW only needing purchasing agreements before they proceed; and
- Additional CEC renewables for the next ten years being supported by the $135 million per year from the PGC.[5]

As the result of the net-effects of all of these, SCE is forecasting a growing net-long condition for much of the time through 2005.

[4] AB-995

[5] AB-995 – The CEC estimates the capability for providing sufficient support to allow the installation and on-going operation of at least 300 MW of new renewables per year for the duration of the PGC funding. This alone would provide over 1,000 MW of new renewables from existing programs over the next four years.

Economic Assessment Sparse and Ignores Significant Integration and Operating Costs:

In addition to a scant need assessment, there are few details supporting any cost-benefit analysis and comparisons to other alternatives. Further, there isn't any recognition of the significant additional costs needed to integrate and operate many of the recommended resources. These include:

- The 1,000 MW of new intermittent wind, will result in significant ISO scheduling imbalance costs. For SCE's 1,000 MW of existing wind, these costs amounted to nearly $80 million in the year 2001;
- No costs are reflected for the new transmission facilities needed to integrate and transmit much of the identified supply resources (could approach $500 million);
- The potential cost shifting from end-use generation supplies; and
- No inclusion of the on-going operational and incentive costs of the various technologies and demand-side programs.

Widespread Use of Micro-Generators Could Adverse Local System Reliability

Although still unknown, there are operational concerns from the widespread integration of similar and dissimilar DG systems on local system reliability. All of these systems have different controls, different control settings and different electrical characteristics, leading to the potential for serious problems in balancing local real and reactive power, distortions in voltage, and adverse system harmonics as these systems could tend to beat-off one another. SCE believes that some orderly assessment needs to be made before the Authority aggressively pursues bulk procurement of these systems.

Furthermore, unless the micro-turbine systems include thermal recovery equipment, they tend to operate at efficiency levels (25%) well below large central plant gas-fired generation (50%) and emit a greater proportion of emissions than other fossil-fired alternatives.

The DIP Needs To Coordinate With Other Existing State Programs

The DIP should indicate how it's efforts attempt to take advantage of and augment with other existing programs, including the CPUC and CEC's energy efficiency, load management and building standard programs; the CEC's renewable and R&D programs; the CPUC's Power Procurement OII which could likely require utilities to invest in new renewables, and other programs and incentives available to California.

It was only 18 months ago that the Legislature endorsed the annual continuation of nearly $500 million to continue the PGC for up 10 years. Unfortunately, the benefits derived from these programs appear to have been ignored in the DIP, both in terms of forecasting resource need and determining resource selections.

Just last year, the CPUC's energy efficiency program under the PGC secured 1.4 BkWh of measured savings, with these levels of success expected to continue and improve in the years to come. In addition, one of the requirements of the CEC's Renewable program and the CPUC's energy efficiency efforts is to award PGC incentives to "most cost-effective and efficient" resource alternatives. Yet it appears in reviewing the DIP, that most of the 800 MW of CEC selected renewable resources were not targeted.

Little Discussion of Cost Recovery and How the $4.7 Billion is Repayed

The whole issue of cost recovery and who pays appears to be missing. Other than in tabulating the expected revenues on page 46, the four page Financial Plan is silent on where the $1.3 billion in 2002-2006 revenues supporting the issuance of $4.7 billion in debt is derived. Further, there isn't any discussion on non-bypassability of those costs, *nor the requirements of non-investor owned utilities and agencies to share in the cost.*

Real Time Meters versus Time-Of-Use

From SCE's perspective, there continues to be uncertainty over both the public acceptance and operational value of a widespread penetration of RTM and hourly pricing, as compared to the use of Time-of-Use meters. The Legislature recognized this in PUC Code 393 requiring pilot studies for small customers to determine the relative value of the benefits derived from real-time and time-of-use metering.

Assumed 3.3% Annual Load Growth Appears High

During the four year period from 2002-2006, the CPA assumed a growth rate of over 3.3%[6]. SCE believes it is too early to say conservation efforts are tapering off to a point that loads will grow at a level significantly higher than pre-2001 long-term growth rates, particularly given current electricity prices, increased energy efficiency efforts and the continuing public awareness to conserve.

CPA Needs To Perform Additional Due Diligence Before Committing Funds:

At this point, SCE believes it is inappropriate for the CPA to rely solely on Letters of Intent and program potential assessments as the basis for their Plan. Substantial due diligence and project/program assessment remains and the CPA should be required to demonstrate the effectiveness of each program and project before it commits funding.

Despite Transmission Congestion Concerns, Most of the New Supply is in the South:

The issue and concerns of transmission constraints prevail throughout the DIP, including a discussion on the need for higher reserves in Northern California due to constraints in that region. What is curious is that of the 2,540 MW of new renewable capacity identified in Attachment 2, nearly 70% reside in the southern zone. If transmission constraints are a concern, this zonal allocation needs to be reversed when additional supply resources are found to be needed.

We appreciate the opportunity to comment on your Investment Plan and look forward to future discussions with the Authority.

Sincerely,

Gary L. Schoonyan

[6] Forecast 2006 demand = 58,510 and forecast 2002 demand = 51,277: 58,510/51277 = 1.14 = 3.3%/year compounded